Indiana Utility Regulatory Commission

2005

Electric Report to the Regulatory Flexibility Committee of the Indiana General Assembly

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PURPOSE AND SCOPE OF REPORT

This report is intended to satisfy the requirements of Ind. Code §8-1-2.5-9(b). The report outlines the status of the Indiana electric utility industry. The report reviews the activities of the electric industry in Indiana and provides an update of facts and developments since the Indiana Utility Regulatory Commission's 2004 Energy Report.

EXECUTIVE SUMMARY AND HIGHLIGHTS

Electricity is something that many people take for granted. Today, electricity is a necessity, driving our economy and improving our quality of life. Further, as technology advances, the "quality" of electricity has become increasingly important. Sensitive electronic equipment in our homes and businesses require reliable electricity to function properly.

Five major investor-owned electric companies, 79 municipally-owned and 41 distribution cooperatives supply the electric needs of Hoosiers. The need for new generation coupled with efforts to meet federal environmental mandates is impacting the price that we pay for electricity. These dual circumstances have resulted in many of the notable proceedings that have occurred before the IURC in the past year. First, the recovery of capital spending on the installation of new pollution control equipment due to air quality regulations has resulted in recurrent cost recovery proceedings before the Commission. Second, certificate of need proceedings have taken place due to utility requests to build new power plants or purchase existing power plants to meet the increasing demands of their customers.

Environmental Policy

In March, 2005, the U.S. Environmental Protection Agency ("EPA") released two new rules limiting the emissions from power plants in the eastern United States. The Clean Air Interstate Rule ("CAIR") mandates reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") emissions in order to help over 450 counties in the eastern U.S. to meet EPA's protective air quality standards for ozone or fine particles. The CAIR directs the affected states to achieve the reductions by updating their existing State Implementation Plans ("SIPs"). The Clean Air Mercury Rule ("CAMR") limits mercury emissions from new and existing coal-fired power plants and creates a market-based cap and trade program that will reduce emissions in two phases.

Regional Transmission Organizations and Markets

The development of Regional Transmission Organizations continues. The Midwest Independent Transmission System Operator ("MISO") implemented wholesale day-ahead and real-time energy markets in its footprint on April 1, 2005. These energy markets seek to optimally dispatch all generation facilities within its region. Indiana MISO members operate their systems in response to price signals issued by the MISO. The move to the operation of Day-Ahead and Real-Time energy markets in the MISO has been combined with a major effort to improve the reliability of the bulk transmission system throughout the region.

American Electric Power Company ("AEP") began taking transmission service as a member of PJM on October 1, 2004. The FERC initiated a proceeding in 2003 to accomplish this, and it made a preliminary finding that AEP's voluntary commitment to join PJM was further designed to obtain economic utilization of facilities.

The MISO and PJM, which both operate in Indiana, are working toward creating seamless operations to serve wholesale electricity customers across 22 states, and parts of Canada. The IURC is a member of the Organization of MISO States, an organization that coordinates state participation in the stakeholder advisory process for the MISO. Each state retains its existing authorities, but it is anticipated that an improved understanding of regional issues will develop and lead to better decisions, especially with regard to capital investments for transmission expansion.

Energy Policy Act of 2005

In the summer of 2005, the U.S. Congress passed the comprehensive Energy Policy Act of 2005 ("EPAct 2005"). The Act was signed into law by the President on August 8, 2005. Title XII of the Act is the Electricity Title. This section covers the areas of reliability, transmission, market transparency, merger review, future generation technologies including clean coal gasification, climate change, tax provisions, the repeal of PUHCA, and changes to PURPA. The new legislation requires federal and state authorities to take a number of actions covering a time frame of a few months up to three years.

Commission Rulemakings

The Commission's ongoing interest in distributed resource issues has resulted in the promulgation of two general rules. First, the Net Metering Rule (codified as 170 IAC 4-4.2) became final on December 21, 2004. Net metering is an arrangement in which an eligible customer generator interconnected with its utility can flow energy both to and from the distribution grid and be billed only for their net energy consumption. The rule applies to each Indiana investor-owned electric utility and directs them to provide the opportunity of net metering to residential customers and K-12 schools. The rule further outlines the terms and conditions under which this opportunity must be offered. The basis and intent of the rule is to encourage small-scale renewable energy projects among the populace so as to allow users a measure of energy independence without jeopardizing the safety, energy cost or service quality of others on the interconnected grid.

The second rule is the proposed Interconnection Rule. The Interconnection Rule covers all interconnections between Indiana investor-owned electric utilities and their customers who wish to generate power with their own generator. The rule makes the interconnection process between utilities and customers more transparent and consistent across the state.

Informal IRP Review

Following the utilities' submittals of their 2003 Integrated Resource Plans, the Commission requested that the Staff perform a comprehensive review and evaluation of the utilities' IRPs. Following the review Staff drafted a report describing the review process and its findings and recommendations. A final draft of the report was circulated to the utilities and other interested parties for comments to be incorporated into the final document. A final report was presented to the IURC Commissioners on May 13, 2005.

Vegetation Management Policies

As part of the investigation into the August 14, 2003 blackout, the Federal Energy Regulatory Commission ("FERC") directed a study on the vegetation management policies of the electric utility industry. In September, 2004 the FERC submitted a report to Congress summarizing its findings and recommendations. Using this information as a template, the IURC staff began its own examination of Indiana's electric utilities' vegetation management practices.

The objective of this research was to consider vegetation management from a statewide perspective without judging the effectiveness of the utilities' programs. Staff discovered a wide range of practices and procedures. Although no significant patterns or trends were identified, some general observations were made.

Merchant Plants in Indiana

Adequate generation capacity, low wholesale market prices and financial instability have affected the development of new generation capacity constructed, owned and operated by independent power producers. The Commission has not received a new petition for the construction of a merchant plant facility since March 2001. Only three approved merchant plant projects remain to be completed or cancelled. Currently, there are approximately 3,786 MWs of generation capacity available from Indiana merchant plant resources.

I. NATIONAL ELECTRIC INDUSTRY ISSUES

A. FEDERAL ENVIRONMENTAL POLICY

Clean Air Interstate Rule ("CAIR")

On March 10, 2005, the U.S. Environmental Protection Agency ("EPA") announced the Clean Air Interstate Rule, a rule which mandates reductions in sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emissions in order to help over 450 counties in the eastern U.S. to meet EPA's protective air quality standards for ozone or fine particles. SO_2 emissions contribute to the formation of fine particles, while NOx emissions contribute to the formation of fine particles and ground-level ozone. According to the EPA, fine particles and ozone are associated with thousands of premature deaths and illnesses each year, the reduction of visibility, and damage to sensitive ecosystems. This rule and its requirements are closely tied to the Clean Air Mercury Rule, also announced in March, and discussed below.

The CAIR directs the affected states to achieve the reductions by updating their existing State Implementation Plans ("SIPs"). CAIR contains a provision that allows states to participate in a cap and trade program to achieve the reductions. CAIR reductions have two phases: In the first phase, SO_2 emissions will be reduced by 4.3 million tons by 2010, representing a 45% reduction from 2003 levels, while NOx emissions will be reduced by 1.9 million tons by 2009, representing a 53% reduction from 2003 levels. By 2015, the second phase of CAIR will reduce SO_2 emissions by 5.4 million tons, representing a 57% reduction from 2003 levels, while NOx emissions will be reduced by 2 million tons, representing a 61% reduction from 2003 levels. At full implementation, SO_2 emissions in the affected states will be 2.5 million tons (compared to 15.7 million tons in 1990); and NOx emissions will be 1.3 million tons (compared to 6.7 million tons in 1990).

The Indiana Department of Environmental Management ("IDEM") will have to submit its rule for Indiana to the EPA by December 2006. IDEM has developed a Utility Rules Workgroup[1], which meets regularly to discuss the CAIR and the mercury rule. More than one

[1] http://www.in.gov/idem/air/workgroups/mercury/

dozen lawsuits against the CAIR were filed in July, 2005. The state of North Carolina and power companies filed lawsuits dealing with technical interpretations of the rule, while the environmental groups are seeking a reinterpretation of the rule to ensure that stricter rules are possible in the future. The environmental groups are not seeking to halt the progress of the CAIR.

Clean Air Mercury Rule ("CAMR")

On March 15, 2005, the EPA issued the Clean Air Mercury Rule. The rule is the first federal rule to permanently cap and reduce mercury emissions from coal-fired power plants. The CAMR establishes "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap and trade program that will reduce emissions in two phases. The first phase cap, effective in 2010, is 38 tons of mercury (compared to 48 tons currently). These emission reductions will be substantially or wholly achieved through "co-benefits"—meaning that the technologies applied to reduce NOx and SO_2 for the CAIR will also reduce mercury emissions.

The second phase of the CAMR is effective in 2018, with a limit of 15 tons of mercury across the industry. IDEM has started to develop the mercury rule for Indiana by publishing a First Notice of Comment Period in the June 1, 2005 Indiana Register.[2] The Indiana State Plan is due on or before September 15, 2006. The cap and trade program creates a mercury budget for each affected state. The budget for Indiana for 2010-2017 is 2.098 tons (compared to current estimated annual emissions of 2.5 tons) per year, which is a 15% reduction from 2002 levels. The budget for 2018 and beyond is 0.828 tons, which is a 66% reduction from 2002 levels. The budget levels are permanent, regardless of any growth that may occur for coal-fired power plants in Indiana. Thus, any new plants would need to obtain mercury allowances from the market or other sources (such as a plant retirement) in order to operate.

Several states and environmental groups have sued the EPA in federal court over the rule. They argue that EPA has violated a provision of the Clean Air Act, which requires utilities to use the best-available technologies to reduce their mercury emissions. In addition, many of

[2] http://www.in.gov/legislative/register/June-1-2005.html

the same parties, under another part of the Clean Air Act, have asked the EPA to reconsider CAMR. The possible delays due to litigation could cause the deadlines of the rule to be pushed back, as happened during the last significant EPA rule, the NOx SIP Call.

Indiana Utility Environmental Compliance Plans

Indiana electric utilities have begun to plan and prepare their systems for compliance with the recently issued CAIR and CAMR environmental mandates. Indianapolis Power & Light ("IPL") , PSI Energy ("PSI) and Southern Indiana Gas & Electric Co. ("SIGECO") have petitioned the Commission for approval of their individual compliance plans, IPL's request has been approved by the Commission.

These environmental compliance plans and associated cost recovery are addressed in various Indiana statutes; Ind. Code §8-1-8.7 governs the issuance of a Certificate of Public Convenience and Necessity ("CPCN") for the construction of Clean Coal Technology ("CCT"); Ind. Code §8-1-8.8 directs the Commission to encourage clean coal projects through the application of financial incentives and timely recovery of costs associated with such projects; and Ind. Code §8-1-2-6.6 and 6.7 discuss ratemaking treatment for CCT. These statutes generally serve to encourage the use of Illinois Basin coal through the installation of CCT equipment by allowing the utilities to earn a return of and on such investments outside of a normal rate case proceeding and allowing extra ordinary ratemaking treatment.

The primary methods utilized for reducing the quantity of SO_2 discharged by coal-fired generation plants are the installation of a Flue Gas Desulfurization system ("FGD" or "scrubber") on a unit or switching to a lower sulfur content coal to burn in a unit. Popular methods for reducing NOx emissions by coal-fired generation are the installation of Selective Catalytic Reduction equipment ("SCR") or the use of advanced boiler equipment and programs aimed at reducing the burn temperatures. Mercury emission reduction technology is less developed to date but includes equipment such as Activated Carbon Injection ("ACI") and Baghouse units. Additionally, mercury emissions are significantly reduced as a co-benefit of SCR/FGD combination installations. The reduced use of coal-fired generation through conservation or fuel switching could also provide a means to reduce the above mentioned pollutants.

Indianapolis Power & Light

IPL sought approval of modifications to its CPCN, granted in Cause No. 42170, for construction of CCT projects; for ongoing review of CCT projects; for the use of qualified pollution control property; for ratemaking treatment of construction costs; and for depreciation and cost recovery treatment in Cause No. 42700, filed July 30, 2004.

IPL's requested plan modification increased approved construction costs by $182 million; composed primarily of the addition of an FGD at its Harding Street Unit 7 and enhancements to the existing FGD on Petersburg Unit 3. The utility and the OUCC filed a Stipulation and Settlement Agreement which endorsed the plan modification and included ratemaking treatment. This treatment authorized, among other things, IPL to earn a 7.7% rate of return on the new CCT projects, set a 6.11% annual depreciation rate for 18 years, and allowed for recovery of operation and maintenance costs following the placement of any project in-service.

The Commission granted IPL's requested plan modification along with the Stipulation and Settlement Agreement on November 30, 2004.

PSI Energy

PSI filed a petition on September 2, 2004, Cause No. 42718, which requested approval of a proposed compliance plan to meet the above mentioned emission mandates. Hearings were held May 9 and 10, 2005, on its request. An order has not been issued to date.

PSI's proposed plan includes estimated construction costs of $1.16 billion; composed primarily of 5 FGD additions, 2 FGD upgrades, and 2 common ACI-Baghouse installations. PSI has also requested ratemaking treatment that includes an enhanced return on their investment, accelerated depreciation and on-going recovery of CCT operation and maintenance expenses.

Southern Indiana Gas & Electric Company

SIGECO filed a petition on May 16, 2005, Cause No. 42861, which requested approval of a proposed compliance plan to meet the new emission mandates. The petition outlines a compliance plan that includes the addition of 1 FGD and 1 fabric filter. No cost estimates were included in the petition. Evidentiary hearings are scheduled for October 26 and 27, 2005.

B. REGIONAL TRANSMISSION ORGANIZATIONS

A regional transmission organization ("RTO") is an independent entity that monitors electric reliability throughout a geographic region and is responsible for coordinating the wholesale electric transmission system in the region. When a utility company joins an RTO it must transfer operational control, but not ownership, of its transmission system to an independent entity. The dispatch of generation is the principal means by which the system operators manage the transmission grid and keep the grid within the physical limits for safe and reliable operations.

Centralized economic dispatch permits the generation resources throughout the regional transmission system to meet the demand for electricity at the lowest possible production costs. Economies can be gained through load diversity across the broader region that makes possible more extensive use of lower cost generation anywhere in the region.

RTOs have been developing in the Midwest for several years. The IURC has followed and participated in the process and has reported on these activities in previous reports to the legislature. The following is a summary of RTO developments for the past year.

Midwest Independent Transmission System Operator ("MISO")

The MISO was formed by transmission owners in 1996, and is based in Carmel, Indiana. The MISO's main responsibility is to ensure the safe, reliable transfer of power in the Midwest and to ensure fair access to the transmission system. The area served by the MISO covers 947,000 square miles with 97,000 miles of high voltage transmission lines, and stretches from Pennsylvania to Nebraska and from Tennessee to the Canadian province of Manitoba. The Midwest ISO has 517 employees and two control centers – one located at the Carmel headquarters facility and another facility in St. Paul, Minnesota. Several Indiana electric utilities are currently members of the MISO: PSI, IPL, SIGECO, Wabash Valley Power Association ("WVPA"), Hoosier Energy, Indiana Municipal Power Agency ("IMPA") and Northern Indiana Public Service Company ("NIPSCO").

PJM

AEP, with electric utility operations in Indiana[3], Kentucky, Ohio, Tennessee, Virginia and West Virginia, transferred functional and operational control of its transmission assets to PJM at midnight on October 1, 2004. The PJM is the RTO responsible for the operation and control of the bulk electric power system throughout all or portions of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. On October 1, 2004, PJM began managing the flow of wholesale electricity over more than 23,000 additional miles of high-voltage transmission lines and extended the scope of its competitive wholesale electricity trading markets. Of the additional lines, 22,300 miles are owned by AEP and 1,000 miles are owned by Dayton Power and Light Company.

The Midwest Market Initiative – Economic Benefits

On April 1, 2005, the MISO began operating both Day-Ahead and Real-Time energy markets to arrive at an optimal dispatch solution for all generation resources within its region. This enables the Midwest ISO to ensure that all load requirements in its region are met reliably and efficiently.

The MISO and the PJM schedule and dispatch generation in their region using a security constrained dispatch methodology based on the prices and operating characteristics offered by generation owners in the region. This methodology results in the most economical use of resources at any given moment for the entire region, taking into account all transmission constraints, while ensuring that sufficient generation is dispatched to meet the energy requirements of the region.

[3] Indiana Michigan Power Company is the AEP subsidiary that operates in Indiana.

The Midwest is a highly integrated portion of the bulk power system, and experiences substantial flows of power between the states. These flows can cause congestion on the transmission system. Congestion occurs when a transmission facility is either loaded in excess of its engineering rating for reliable operation or would be in excess of its rating in the event of a contingency. The primary means of relieving congestion is to change the output of generation at different locations on the grid. This "redispatch" can be implemented through non-market procedures or market-based procedures.

Transmission Loading Relief ("TLR") is an administrative procedure to keep transmission facilities from exceeding their limits and was used by the MISO as a primary means to control congestion prior to market start-up. TLRs do not consider the costs of changing generation or the costs of different redispatch options. The current market-based procedure used by the MISO relieves the constraint by sending generation owners price signals. These price signals, called Locational Marginal Pricing ("LMP"), consider both the impact of specific generators on the constrained facility and the cost to change the generation output.

Uncoordinated and separate dispatches by individual utility companies in response to congestion will not produce the same result as a region-wide dispatch coordinated by an RTO. The sum of stand-alone least cost dispatches by utility companies will produce higher costs than a regional least cost dispatch where transmission constraints can be relieved by the dispatch of the most economical generation regardless of utility ownership.

The MISO performed an analysis in 2004 that showed the introduction of centralized security constrained economic dispatch using LMP should result in annual gross production cost savings of approximately $255 million throughout the MISO region. This analysis also concluded that regional dispatch will allow for more efficient use of existing transmission and generation facilities, which will not only lower spot energy prices, but also put downward pressure on prices in wholesale power purchase contracts, resulting in a potential annual gross savings of approximately $713 million to energy consumers.

MISO Activities to Improve Reliability

The move to the operation of Day-Ahead and Real-Time energy markets in the MISO has been combined with a major effort to improve the reliability of the bulk transmission system throughout the region.

1. State-of-the-Art Tools

The MISO has developed tools to observe in real time the performance of the transmission system in its region and adjacent regions. These tools monitor all transmission lines and transformers over 100 kV and others that are identified as critical to maintaining reliable system operations. A State Estimator takes information from 96,000 points on the transmission grid and gives system operators a detailed update of the entire system every 90 seconds. A Contingency Analysis Tool runs more than 5,000 potential scenarios every eight minutes. These tools allow transmission operators to rapidly identify changes in operating conditions and to determine whether new operating conditions require action to assure the reliability of the transmission grid.

2. Coordination with Adjacent Transmission Systems

While the consolidation of individual utilities into RTOs reduces the number of borders or seams across which transmission systems have to be coordinated, seams remain between the RTO and surrounding non-RTO member utilities. The MISO has pursued arrangements to better coordinate transmission operations with bordering utility systems or RTOs. An example is the Joint Operating Agreement ("JOA") between the MISO and PJM which calls for significant operational data exchange, the sharing of information regarding emergency protocols, and the coordination of system planning.

The goal of coordination agreements is to reduce the reliability risks associated with these border areas. The risks are caused by poor visibility, a lack of understanding of what is happening in the adjacent transmission system, and questionable accountability. Agreements like the JOA improve the exchange of information, clarify authority and responsibility, and specify the appropriate procedures to be implemented in specific circumstances.

In April 2005, the MISO, PJM and the Tennessee Valley Authority ("TVA") signed a Joint Reliability Coordination Agreement ("JRCA") that provides for cooperation in the management and operation of the electric grid over a major portion of the eastern United States. The JRCA will result in the active management of the borders of the MISO, PJM and TVA. The parties will share critical operating information, transmission system models and extensive planning data to ensure that all have the best information possible in their day-to-day operations. The information sharing will enable each transmission operator to recognize and manage the effects of its operations on the adjoining systems. The three organizations have also agreed to conduct joint planning to ensure that transmission investments and improvements are undertaken in a cost-effective manner and without adversely affecting reliability to any organization's customers.

3. Regionally Coordinated Planning of Transmission Expansion

On June 16, 2005, the MISO Board of Directors approved a long-term transmission expansion plan that includes recommendations addressing the need for transmission infrastructure additions and improvements throughout the Midwest region. The 2005 Midwest ISO Transmission Expansion Plan ("MTEP") is an in-depth examination and analysis of the entire region's transmission needs.

The MISO performs regionally coordinated transmission expansion planning that benefits the region by providing expansion decisions that are both more cost-effective and reliability-enhancing than would be the case with planning done at the individual utility level. A utility planning for its own requirements results in transmission expansion and investment decisions that are optimized for the individual utility service territory. However, individual utility company plans are unlikely to provide the optimal plan for the combined region given the highly interdependent nature of the transmission grid.

The 2005 MTEP identifies 615 "planned" or "proposed" transmission facility additions or enhancements, representing an investment of $2.91 billion through 2009. MISO transmission owners are expected to make the investments necessary to implement the planned projects recommended in the MTEP. Projects that are designated as "planned" are recommended by the MISO to be completed by the service dates identified. Other projects, listed as "proposed," are tentative solutions to identified needs and require additional planning before they are endorsed by the MISO as preferred solutions.

The 2005 MTEP is the second regional expansion plan produced by the MISO since the start of operations in February 2001. The first regional plan, approved in June 2003, identified 407 facility additions, with an estimated investment of $1.9 billion.

Commitment to Complete Joint and Common Market

In December 2004, the Midwest ISO and PJM reaffirmed their commitment to complete a joint and common market that will ultimately serve wholesale electricity customers throughout the Midwest and mid-Atlantic regions. Formation of a joint and common market between the two organizations is being accomplished through a JOA between the two RTOs that was signed in December 2003. The JOA outlines how coordination procedures will be phased in as the MISO and PJM energy markets develop. On March 3, 2005, the FERC issued an order that directed the MISO and PJM to lay out a schedule that, barring significant unforeseen events, facilitates the filing on October 1, 2005 of a more specific plan for continuing the development of a joint and common market.

Organization of Midwest ISO States ("OMS")

The OMS coordinates state participation in the MISO stakeholder advisory process; coordinates state input to FERC when possible; and facilitates the sharing of information and analysis of issues. Each state retains its existing authorities, but it is anticipated that an improved understanding of regional issues will develop and lead to better decisions, especially with regard to capital investments for transmission expansion.

The OMS formulates positions through its work groups that participate in the Midwest ISO stakeholder meetings and the work groups discuss the issues among themselves. The OMS currently has eight working groups: Congestion Management and FTR Allocation; Demand Response; Market Monitoring and Market Power Mitigation; Market Rules and Implementation Timelines; Pricing; Resource Adequacy and Capacity Markets; Seams Issues; and Transmission Planning and Siting.

Recent activities of the OMS include:

- ● Filing comments with the FERC on state commission access to confidential data, Docket Nos. ER04-691-024 and EL04-104-023, March 25, 2005 and March 11, 2005.
- ● Filing comments with the FERC on Midwest ISO transmission and energy markets tariff, Docket Nos. ER04-691-025 and EL04-104-024, February 25, 2005.
- ● Filing comments with the FERC on financial reporting and cost accounting for RTOs, Docket No. RM04-12-000, November 15, 2004.

MISO Cost Recovery Case, Cause No. 42685

On July 9, 2004, PSI, IPL, NIPSCO, and SIGECO ("Petitioners") filed a joint petition seeking approval of certain changes in operations that are likely to result from their participation in day-ahead and real-time energy markets being implemented by the MISO, and for a determination of the manner and timing of recovery of costs resulting from implementation of the MISO energy markets.

The Petitioners described the transfer of their control area operation responsibilities to the MISO as a result of the start-up of the day-ahead and real-time energy markets. An agreement between the MISO and all MISO control area operators specified the allocation of tasks, and the responsibilities associated with those tasks, between the MISO and the control area operators. The Petitioners also explained that the fundamentals of economic dispatch and the hedging of price risks will not change with participation in the MISO's energy markets, but that decisions regarding self-scheduling of resources, the preparation and submission of generator offer curves in the day-ahead and real-time markets, the amount of retail load to schedule in the day-ahead market, and the acquisition of financial transmission rights will all affect the resources used and the costs incurred to serve retail customers.

The costs the Petitioners sought to pass on to ratepayers can be categorized as either charges billed by MISO to market participants or internal costs incurred by the Petitioners.

A final order was issued on June 1, 2005. The commission order authorized the transfer of control area operations tasks and responsibilities to the MISO, and also authorized the transfer of dispatch and energy market tasks and responsibilities to the MISO. The cost recovery determinations reflected the different statutory provisions that apply depending on whether the costs are fuel or non-fuel related, and also took account of prior Commission determinations in other proceedings that affected the regulatory status of each Petitioner.

C. FEDERAL ENERGY BILL

In the summer of 2005, the U.S. Congress passed the comprehensive Energy Policy Act of 2005 ("EPAct 2005"). The Act was signed into law by the President on August 8, 2005. Title XII of the Act is the Electricity Title. This section covers the areas of reliability, transmission, market transparency, merger review, future generation technologies including clean coal gasification, climate change, tax provisions, the repeal of PUHCA, and changes to PURPA.

One of the mandates that the Federal Energy Regulatory Commission must meet is that within six months, it must issue a rule to set up and certify an electric reliability organization to develop and enforce mandatory standards for users of the bulk power system. The FERC is also required to develop incentive rate treatments for transmission investment within one year.

The Act gives FERC, in limited situations, the authority to site transmission projects that have not otherwise been approved by state siting authorities. FERC is also authorized to approve participant funding plans to allocate costs for new transmission projects without regard to whether the applicants are members of a regional transmission organization as long as the resulting rates are just and reasonable

EPAct 2005 repealed the Public Utility Holding Company Act of 1935 ("PUHCA"). This act regulated the ways in which electric holding companies were allowed to merge into larger companies. With the repeal of PUHCA, FERC was given new merger review authority, and new authorities regarding access to books and records of public utility companies were put into place, along with rulemaking tasks in this area that the FERC must carry out within three to four months.

A Clean Coal Power Initiative was included in the Act. This initiative will provide federal funds to encourage commercial scale development of coal-based gasification technologies that will have significantly lower emissions of sulfur dioxide and nitrogen oxides than existing coal generating plants. .

EPAct 2005 makes changes to the Public Utility Regulatory Policies Act. Some of these changes mandate that state regulatory authorities consider enacting rules (if they have not already done so in the previous three years) in the areas of net metering, interconnection, and time-based meters and demand response programs.

II. INDIANA ELECTRIC INDUSTRY DEVELOPMENTS

A. SIGNIFICANT DECIDED / PENDING CASES

I & M / AEP Operating Agreement Investigation, Cause No. 42045 S-1

On March 2, 2004, the Indiana Office of the Utility Consumer Counselor ("OUCC"), the I&M Industrial Group, the Citizens Action Coalition of Indiana ("CAC") and the Commission staff, filed a Joint Motion to Reopen Investigation in Cause No. 42045. Docketed as Cause No. 42045-S1. The Joint Motion states that if I&M is no longer required to fulfill its obligations resulting from the settlement in Cause No. 42045, then the matters giving rise to the initial investigation would require review, and potentially, new resolution.

On March 14, 2005, the Commission Staff, I&M, the I&M Industrial Group and the OUCC (the "Settling Parties") filed a Settlement Agreement and requested Commission approval thereof without modification or further condition. The CAC did not join in the settlement. Some of the main provisions of the Settlement Agreement are:

- A base rate freeze period beginning January 1, 2005 continuing through June 2007. During this period, the Settlement Agreement also provides that I&M will not file a petition, which, if approved, would have the effect either directly or indirectly, of authorizing a general increase in basic rates to become effective prior to June 2007;
- A fixed fuel rate period beginning with the billing month of March 2004 continuing through June 2007. The fixed fuel rate can be circumvented and actual cost applied during certain extended outage conditions at either of the units at the Cook Nuclear Plant;
- Refund to customers if fuel costs collected over the period are higher than actual fuel costs;
- Performance credit to I&M related to the monthly capacity factor of the Cook Nuclear Plant; and
- FAC's not subject to procedures of Cause No. 41363 (Purchase Power Benchmark).

On June 1, 2005, the Commission issued an order in Cause No. 42045-S1 approving the Settlement Agreement in its entirety and without change.

Three Interrelated NIPSCO Cases, Cause Nos. 42643, 42658, 42824

1. City of Gary's Request for the Valuation of NIPSCO'S Mitchell Plant Cause No. 42643

On May 7, 2004, the City of Gary petitioned the IURC to value NIPSCO's Mitchell Plant ("Mitchell"), a 500 MW coal-fired generating facility mothballed since June 2002, so that the city may exercise its right to acquire the property. The City of Gary plans to use the Mitchell site for an expansion of the Gary/Chicago airport and for various other commercial, residential, and recreational projects. In order to value Mitchell, the City of Gary has asked the Commission to take notice of the facility's current idled status and to take into account the environmental remediation necessary before development of the site can occur.

On November 29, 2004, the City of Gary and NIPSCO filed a Joint Development and Marketing Agreement with the Commission. The agreement calls for NIPSCO and Gary to cooperate in pursuing governmental or alternative funding for the demolition of the structures currently located at the Mitchell site and for potential environmental remediation costs. The agreement states that no demolition or remediation costs will be borne by NIPSCO, its customers, or its parent company. The agreement also states that if governmental or alternative funding is sufficient to cover demolition and remediation costs, then NIPSCO will transfer the Mitchell site to Gary for a nominal value.

Evidentiary hearings in this Cause concluded on February 17, 2005. On March 31, 2005, NIPSCO and the OUCC filed a Memorandum of Understanding ("MOU") with the Commission; NIPSCO and the OUCC foresaw, pending the outcome of a study underpinning the MOU, a formal settlement agreement arising from the MOU that would have resolved the issues of this cause and Cause No. 42658. On July 14, 2005, the OUCC filed a Notice of Disavowal of the MOU. The parties subsequently reached a settlement agreement resolving the issues of this cause and Cause No. 42658, and partially resolving the issues in Cause No. 42824. The settlement agreement accepts the agreement reached in this cause between NIPSCO and the City of Gary, filed with the Commission on November 29, 2004.

2. NIPSCO'S Request for a Purchased Power & Transmission Tracker Cause No. 42658

On May 25, 2004, NIPSCO petitioned the Commission for approval of a purchased power and transmission tracker ("PPTT"). NIPSCO plans to use the PPTT to track power purchase costs incurred to fill current capacity deficiencies in intermediate dispatchable power ("IDP") and to track costs incurred by taking transmission service as a MISO member. NIPSCO plans to use the PPTT to flow through all charges relating to purchased power and transmission, as described above, including demand charges, capacity charges, energy charges, brokerage commissions, transmission costs, MISO and GridAmerica charges (net of MISO revenues) and the cost of options and physical derivatives acquired to manage risks associated with purchased power and transmission.

Hearings in this Cause concluded on December 3, 2004. On March 31, 2005, NIPSCO and the OUCC filed a Memorandum of Understanding ("MOU") with the Commission; NIPSCO and the OUCC foresaw, pending the outcome of a study underpinning the MOU, a formal settlement agreement arising from the MOU that would have resolved the issues of this cause and Cause No. 42643. On July 14, 2005, the OUCC filed a Notice of Disavowal of the MOU. The parties subsequently reached a settlement agreement resolving the issues of this cause and Cause No. 42643, and partially resolving the issues in Cause No. 42824. The settlement agreement calls for the withdrawal of NIPSCO's petition in this cause.

3. NIPSCO Request for Authority to Purchase Power from Whiting Clean Energy via EnergyUSA-TPC Cause No. 42824

On April 11, 2005, NIPSCO, Whiting Clean Energy, and EnergyUSA-TPC (Collectively "Petitioners") petitioned the Commission for approval of a purchase power agreement ("PPA") whereby Whiting Clean Energy would sell power to EnergyUSA who would in turn sell said power to NIPSCO. The Petitioners claim that NIPSCO urgently needs the IDP that Whiting will provide in order to reverse NIPSCO's declining performance against NERC's CPS1[4] and CPS2[5] standards. In order to have the IDP available to NIPSCO for the summer

[4] CPS1 is a measurement of how well each control area ("CA") supports the interconnection frequency. A measurement of 100% means the CA is adjusting its generation in a manner that meets its minimum obligation to maintain the interconnection's scheduled frequency.

[5] CPS2 is designed to limit the magnitude of unscheduled interchange. In order to comply with CPS2, each CA must keep its area control error within bounds, as determined by ECAR, 90% of the time each month.

months, the Petitioners requested that the PPA be approved, on at least an interim basis, by June 30, 2005, with full hearings on this matter at a later date. As part of its approval, the Petitioners requested that the Commission make certain public utility holding company act ("PUHCA") findings that would allow Whiting Clean Energy to maintain its status as an exempt wholesale generator ("EWG"). The Petitioners stated that issues such as cost recovery and NIPSCO's need for IDP can be withheld until later full hearings. As such, the Petitioners filed the MOU reached in Cause Nos. 42643 and 42658, as it addresses a study to be performed affirming NIPSCO's need for IDP and cost recovery of IDP resources.

An interim order was issued on July 1, 2005. In its order the Commission gave NIPSCO the authority to purchase power, on an interim basis, from Whiting Clean Energy through Whiting's cost based, FERC approved tariff. The Commission stated that approving the PPA, even on an interim basis, would be premature without full hearings in this cause, and may be viewed as a prejudgment of the issues raised in Cause Nos. 42643 and 42658. Therefore, the Commission decided to not make the requested PUHCA findings in its interim order. Full hearings in this cause are scheduled for later this fall.

On August 22, 2005, the Petitioner's filed with the Commission a settlement agreement reached among the Petitioner's, the OUCC, and various NIPSCO industrial customers partially resolving the issues in this cause and resolving the issues in Cause Nos. 42643 and 42658. The settlement agreement limits the monetary value of the purchases NIPSCO may make under the PPA and the amount and timing of Intermediate Dispatchable Power ("IDP") purchases. The agreement allows NIPSCO to recover fuel and variable operation and maintenance expenses, by way of FAC proceedings, charged to it by Whiting for the production of IDP power. The agreement also calls for NIPSCO to file a rate case petition on or before July 1, 2008.

NIPSCO's Appeal of the Commission's Order in Cause No. 42519

On September 30, 2003 NIPSCO petitioned the Commission for authority to defer MISO Schedule 10 charges that it incurs as a transmission owning member of MISO and to create a regulatory asset to defer these charges. On July 21, 2004, the Commission issued an order denying NIPSCO's request stating that "The relief requested by NIPSCO in this Cause is not contemplated by the Settlement Agreement [Cause No. 41746] and would seemingly act to erode the amount of the credits that NIPSCO agreed to pay under the terms of the Settlement Agreement [Cause No. 41746]". The Commission's conclusion was based in part on the fact that certain accounting standards require NIPSCO, in regard to cost deferral, to have a "reasonable belief that those costs will someday be recovered". The Commission concluded that due to the Settlement Agreement reached in Cause No. 41746, NIPSCO can not have a reasonable belief that someday, deferred Schedule 10 charges will be recovered.

On August 10, 2004, NIPSCO petitioned the Commission for reconsideration of its order; the Commission denied NIPSCO's request for reconsideration on October 6, 2004. NIPSCO subsequently appealed the Commission's July 21, 2004 order to the Indiana Court of Appeals *(Northern Ind. Pub. Serv. Co. v. Indiana Office of Utility Consumer Counselor*, 826 N.E.2d 112 (Ind. Ct. App. 2005)).

On April 27, 2005, the Court of Appeals issued its ruling upholding the Commission's order. The Court of Appeals agreed with the Commission that the distinction NIPSCO made between deferral of Schedule 10 costs and their future recovery should be rejected, that the Commission's order was not made contrary to law, and that NIPSCO may be treated differently than other electric utilities with respect to Schedule 10 cost deferral, since its rate freeze situates it differently.

B. IURC RULEMAKINGS AND OTHER RELATED MATTERS

Net Metering Rulemaking (RM# 03-05)

Following an informal stakeholder process of workshops and written comments about a proposed net metering rule, the Commission published a proposed net metering rule in the April 1, 2004, Indiana Register. Net metering is an arrangement in which customer-owned generation is interconnected with the utility so that energy can flow to and from the distribution grid and the customer is billed only for his net energy consumption. The net metering rule applies to all Indiana investor-owned electric utilities and directs each to provide the opportunity of net metering to residential customers and K-12 schools. The rule is intended to encourage small-scale renewable energy projects, allowing users a measure of energy independence without jeopardizing the safety, energy cost or service quality of others on the interconnected grid.

The rule became final on December 21, 2004 (codified as 170 IAC 4-4.2). Net metering tariffs for the five Indiana investor-owned electric utilities (including revisions to three existing tariffs) were approved in the spring of 2005. On March 1 of subsequent years, the utilities will report to the Commission the number of, type, etc. of net metering customers on their system.

Interconnection Rulemaking (RM# 05-02)

The second phase of the Commission's ongoing interest in distributed resource issues has resulted in the promulgation of a general rule to cover all interconnections between Indiana investor-owned electric utilities and their customers who wish to generate power with their own generator. A draft rule was circulated to stakeholders in late January 2005, and informal written comments were received and circulated in March 2005. A revised draft was approved by the Commission in July 2005, which started the formal rulemaking process. A final rule is not expected before July 2006.

The interconnection rule establishes three levels of scrutiny for proposed distributed resource projects based on the size of the project and other technical parameters. Level 1 is for projects of 10 kW or less; Level 2 for projects less than 2 MW; and Level 3 covers all other projects. The rule will make the interconnection process between utilities and customers more transparent and consistent across the state. Once the interconnection is complete, customers may be able use their generating resource to participate in demand response programs.

2005 Reliability Statistics

On March 1, 2005, Indiana's investor-owned electric utilities[6] submitted their first Electric Reliability Indices Report in compliance with 170 IAC 4-1-23(e)[7]. The 2005 report included data for 2002, 2003 and 2004; subsequent reports will only show the previous year's data.

The report includes data for System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI") calculated with and without major storm events. SAIFI is calculated by dividing the total number of customers experiencing service interruptions over a defined period (in this case one year) by the total number of customers served by the utility. This index indicates how often a customer is likely to experience a service interruption during the year.

SAIDI is calculated by dividing the total duration of service interruptions in hours or minutes over the period by the total number of customers served by the utility. This index indicates how long a customer could expect to be without service over the year.

CAIDI is calculated by dividing SAIDI by SAIFI. This index indicates, on average, the duration of each service interruption. Differing operating and maintenance procedures among utilities may skew the service interruption results such that one utility may have more frequent service interruptions of shorter durations while another could have fewer interruptions of longer durations.

Each utility reported its indices with and without major events. Major events are storms or weather events that are more destructive than normal storm patterns. Each utility tends to define a "major event" slightly differently; therefore some utilities will capture more of their service interruptions in the "without" category than other utilities. This is a reason why one should avoid making direct comparisons among the utilities based on the indices. Service territory geography, size, and customer mix are also factors that make direct comparison of the indices among the utilities difficult.

[6] PSI Energy, Indianapolis Power & Light, Vectren, Indiana Michigan Power and Northern Indiana Public Service Co.

[7] These reports are the result of Rulemaking RM# 04-02, as reported in the 2004 Regulatory Flexibility Report.

Table 2 presents the indices submitted by each utility and a composite set of indices derived from the group. While direct comparisons among utilities should be avoided, some observations can be made.

- Overall it appears that IPL customers enjoy the most reliable electric service. On average IPL customers can expect less than one service interruption per year usually lasting less than two hours. IPL reported one Major Event in each of the reporting years. IPL has a very condensed service territory that is fully developed (no remote or rural areas that may hamper the restoration of service). It should also be noted that IPL has been under a settlement agreement that sets financial penalties for not meeting specified reliability criteria[8]. That settlement agreement expired on March 31, 2005.
- Utilities in the northern half of Indiana (NIPSCO and I&M) tend to have more and longer service interruptions. I&M reported three or more major events in each of its reporting years. NIPSCO did not clearly identify the number of major events it experienced during the reporting periods, but some events did occur. Harsher normal weather conditions in northern Indiana may contribute to more frequent and longer service interruptions for NIPSCO and I&M.
- PSI tended to have more frequent, but shorter, service interruptions in comparison to the composite indices. Although PSI has the largest service territory with remote rural areas, it appears the utility strives to restore service interruptions in a timely manner.
- Vectren reported only one major event, occurring in 2004. Under the heading "Including Major Events", Vectren seems to be in line with the composite indices for 2002 and 2003, but significantly exceeds the composite indices for 2004. It should be noted that Vectren reported no major events for 2002 and 2003. Comparing Vectren to the composite indices under the heading "Excluding Major Events" suggests that Vectren tends to experience service interruptions more frequently but of shorter duration. Vectren's indices tend to suggest that it may need to better prepare for major events.

[8] Order in Cause No. 41962 issued February 6, 2002.

As noted earlier, it may be tempting to be critical of a utility based on reliability indices submitted but further investigation should be conducted before drawing any conclusions.

Table 1: SAIFI & CAIDI Data by Investor Owned Utility

	Including Major Events			Excluding Major Events		
Utility/Index	*2002*	*2003*	*2004*	*2002*	*2003*	*2004*
PSI						
SAIFI	1.57	1.58	1.66	1.36	1.22	1.21
SAIDI	170.0	201.0	255.0	134.0	127.0	124.0
CAIDI	109.0	128.0	153.0	98.0	103.0	102.0
IPL						
SAIFI	1.14	0.90	0.81	1.03	0.79	0.71
SAIDI	132.9	98.0	76.7	73.8	65.7	53.2
CAIDI	113.3	108.4	94.1	72.0	83.2	74.5
Vectren						
SAIFI	1.46	1.27	2.36	1.46	1.27	1.12
SAIDI	164.0	111.0	932.4	164.0	111.0	106.8
CAIDI	107.0	87.0	394.7	107.0	87.0	95.4
I&M						
SAIFI	1.68	1.56	1.42	1.12	0.95	1.25
SAIDI	930.6	594.2	291.4	179.1	128.5	194.1
CAIDI	553.5	380.2	204.7	159.3	135.0	155.6
NIPSCO						
SAIFI	1.41	1.65	1.38	1.15	1.45	1.24
SAIDI	542.4	498.0	314.4	196.2	350.4	238.2
CAIDI	384.0	300.6	227.4	170.4	240.6	192.0
Composite						
SAIFI	1.47	1.43	1.42	1.21	1.13	1.11
SAIDI	390.3	312.8	278.2	145.0	158.0	145.0
CAIDI	265.0	218.3	195.4	119.9	140.2	130.1

Informal IRP Review

In accordance with Indiana Administrative Code Rule 7 Guidelines for Integrated Resource Planning by an Electric Utility ("Rule" or "Rule 7"), eight Indiana utilities[9] are required to submit an integrated resource plan ("IRP") to the IURC every two years. The purpose of the Rule is to ensure that Indiana's electric utilities are adequately planning for the resource needs of consumers and are considering all economically efficient resources to meet those needs.

[9] The eight utilities required to file IRPs are: I&M, IPL, NIPSCO, PSI, SIGECO, Hoosier Energy, IMPA, and WVPA

Over time the Commission and Staff became increasingly disappointed by the depth and quality of the IRPs submitted in response to Rule 7. Some of the IRPs unnecessarily limited the types of resources (both supply- and demand-side) available to meet customer loads. Also, many of the utilities failed to fully evaluate their chosen resource plans through uncertainty analysis. This could potentially result in resource plans that appeared to be economically efficient, but prove to be unrealistic with a relatively minor change in an industry parameter. For example, rising natural gas prices have changed the economic attractiveness of generation fueled by natural gas.

Following the utilities' submittals of their 2003 Integrated Resource Plans, the Commission requested that the Staff perform a comprehensive review and evaluation of the utilities' IRPs. The Staff proposed an informal process that would include meetings with each utility, a comprehensive data request, possibly followed by more detailed data requests and/or meetings with the intent of producing a report that would critique each utility's IRP, and the relevance of the current IRP Rule. A schedule of meetings began in April 2004 and continued throughout the summer until the staff had met with each of the eight utilities.

Following the meetings, the Staff reviewed the information collected through the data requests and drafted a report describing the review process and its findings and recommendations. A final draft of the report was circulated to the utilities and other interested parties for comments to be incorporated into the final document. The report addressed eight areas of the utilities' integrated resource planning.

<u>1. Readability of the report:</u>

Staff believes a well-written IRP report provides a better understanding of the utility's IRP processes and an opportunity for the utility to explain the challenges it faces in meeting the resource needs of its customers. Following the review process, Staff made the following recommendations regarding readability of the report.

- The utilities should include an Executive Summary in the IRP that discusses not only the preferred resource plan but also the development of the IRP, the uncertainties the utility faces going forward and the utility's consideration of those uncertainties and the extent to which outside factors such as technology, the economy and/or regulation have changed since the previous IRP submittal and have affected the current IRP.

- The utilities should include text with each section of the IRP, i.e., load forecast, demand-side resources, supply-side resources, integration process and short-term action plan and not simply provide the information in a graphic or tabular format.
- The utilities should pay attention to the amount of technical language used in the IRP. Staff believes that a reader without extensive technical background should be able to read the IRP and gain a fair understanding of the process and results. A glossary and list of acronyms may be a helpful addition for the non-technical reader.
- The utilities should include a cross-index of the report sections with the provisions in the Rule to make it easier to review their IRPs.

2. Scope of resource options:

Rule 7 explicitly requires the utility to consider a wide range of demand side and supply side resources in meetings its customers' load.

Based on the review process, Staff recommended that the utilities maintain an on-going evaluation of potential demand and supply side options. A written discussion in the IRP report of the options reviewed and ultimately included in the integration process would allow the utility to elaborate on why a potential resource did not fit the needs of the utility, was not a cost effective option or, possibly, why the resource technology was not a commercially available option.

3. Continuity of the IRP process:

Staff examined how the information necessary for the development of the IRP flowed through the utility. To the extent that information is developed by different departments or divisions of the utility and then input into various models used to produce the IRP, there is an increasing risk of inconsistency in the underlying assumptions and/or sources of data.

Staff recommended that utilities make sure that there is one person responsible for the coordination of the IRP data to assure that information is developed based on consistent assumptions.

4. Uncertainty, scenario and sensitivity analysis:

Staff believes that uncertainty analysis provides the utility with an opportunity to test the robustness of its IRP against possible changes in the industry.

Following the review, Staff recommended that the utilities take a broader approach to their uncertainty analysis, in addition to the High/Low cases typically presented.

5. Use of the IRP by the utility:

Staff explored to what extent the utility actually used the IRP in planning for the future as opposed to simply preparing the report to meet its Rule 7 compliance requirement.

During the review process, Staff found that some of the utilities prepared their IRPs simply to comply with the Rule. In order to motivate the utilities to take the process more seriously, Staff recommended that the Commission take more notice of utilities' IRPs in deciding formal proceedings where supply and/or demand resources are at issue even if an integrated resource plan was not filed in the case.

6. Technical input and support:

Staff reviewed the extent to which the utility used outside or third-party sources of data and technical expertise. In general, Staff found that the utilities made appropriate use of outside sources of data and technical support. Because third-party resources are sometimes criticized or questioned in formal proceedings where the IRP is presented, Staff recommended that the Commission be open to the use of outside input or technical support in the development of the utilities' IRPs.

7. Utility comments on the IRP rule:

The electric utility industry has changed significantly since Rule 7 was promulgated. Staff explored with the utilities whether the Rule required changes to more adequately capture the planning process necessary in today's industry. Although the utilities did offer some suggestions to modify the IRP Rule, they generally agreed that the changes were not significant enough to require a formal modification to the Rule. Therefore, Staff made no recommendation on Rule modification.

8. Confidentiality:

Staff reviewed whether special consideration should be extended to the IRP regarding the confidentiality of the information contained in the plans. Staff recommended that the Commission move swiftly on petitions for confidentiality in cases where the confidential data is limited in scope and/or evidence is deemed confidential by FERC or a confidentiality agreement is presented. For requests for confidentiality for information falling outside the parameters previously suggested, the Commission should require compelling evidence before further limiting publicly available data.

The Staff presented a final report to the Commissioners on May 13, 2005.

GIS / Service Area Mapping

A series of public workshops held in 2003 and 2004 focusing on electric utility service and reliability led the Commission to explore alternatives to the present service area mapping archive. Currently the Commission utilizes a manual process based on pen and ink changes to the original mylar maps created in the early 1980's. Technology advances provide more detailed, robust and user-friendly alternatives for consideration. The workshop participants brought their technical expertise to the discussion and provided a range of options which included computer-based mapping using Geographic Information Systems ("GIS") technology. The Commission continued to explore the GIS option for synergies among the various non-electric utilities and the active programs already underway throughout Indiana via discussions with the electric utilities, GIS industry experts and providers, and the non-electric utilities in Indiana. These explorations led to the recent start of a docketed proceeding, Cause No. 42868, seeking to modify the form and maintenance of maps of assigned service areas established pursuant to Ind. Code §8-1-2.3-1. Representatives for each electric utility in Indiana joined in filing the petition on May 26, 2005.

Utility Vegetation Management Report

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The blackout started in an area of northern Ohio and affected an estimated 50 million people in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the

Canadian province of Ontario. The resulting investigations concluded that one of the primary causes of the blackout was inadequate utility vegetation management ("UVM").

The FERC and the National Association of Regulatory Utility Commissioners ("NARUC") ad-hoc Committee on Critical Infrastructure, including former IURC Commissioner Judith Ripley, conducted an investigation of UVM practices of all designated transmission owners. Then, in September 2004, the FERC submitted a report to Congress summarizing its findings and recommendations. Using this information as a template, the IURC staff began its own examination of Indiana's electric utilities UVM practices.

The objective of this research was to consider vegetation management from a state wide perspective, without judging the effectiveness of the utilities' programs. In an effort to better understand the individual utility approaches to vegetation management, Staff reviewed the utilities': 1) reliability indices; 2) UVM operations; 3) rights-of-way documentation; 4) membership in associations and organizations; and 5) comments on the proposed North American Electric Reliability Council ("NERC") standards.

Given the vast differences in the functional, geographical and operational make-up of the responding utilities, Staff discovered a wide range of practices and procedures. Although no significant patterns or trends were identified, some general observations were made.

- The size of the utility gives some indication of how well the utility's vegetation management practices are documented.
- There is a wide variety of programs that work to reduce or prevent vegetation-related outages which focus primarily on safety and tree-trimming practices.
- As utilities seek to improve their vegetation maintenance practices, a greater emphasis is placed on vegetation management provisions of right-of-way agreements.
- Some utilities have asked for the Commission to take a more active role in supporting the utilities' efforts.
- Many Indiana utilities were either unaware of utility vegetation management organizations and associations or were unsure of the benefits of participating in such organizations.

Awaiting Congress to enact the needed reliability legislation, NERC has enhanced its compliance enforcement program by posting on its website the names of organizations found in violation of NERC and regional reliability standards. Staff will continue to review the annual submittal of reliability indices by the investor-owned utilities as an objective means of monitoring these companies' overall reliability. For municipal and REMC utilities, a periodic survey of vegetation management practices and reliability may be in order.

C. MERCHANT PLANTS

The Indiana Utility Regulatory Commission received its first "merchant plant" petition in November 1998, following an early summer price spike in the wholesale power market. Unprecedented wholesale power prices again in the summer of 1999 further encouraged the development of merchant plant projects in Indiana. Through March 2001, the IURC received a total of 26 petitions for what were categorized as merchant plant projects. The IURC has not received any new merchant plant petitions since that time.

Merchant plants are generating facilities that are constructed to sell electricity into the competitive wholesale generation market. The companies that construct merchant plants take the full risk of the cost of construction and operation, which is in contrast to traditionally regulated utilities that build generating facilities with IURC approval and may then recover the cost through the regulated ratemaking process.

Petitioners for merchant plant projects requested that the IURC either find that the facilities are not public utilities under Ind. Code §8-1-2-1 or, in the alternative, decline jurisdiction over the construction and operation of the facilities.

The IURC found that the petitioners were, in fact, public utilities under Ind. Code §8-1-2-1. However, the petitioners were not exercising any rights, powers or privileges of public utilities, such as eminent domain or public rights-of-way, and would not be selling electricity to retail customers or recovering any costs through a rate base. Because of these circumstances the IURC in large part declined jurisdiction over the petitioners and their construction and operation of the proposed merchant plants.

Since the initial merchant plant petition in 1998, the electric utility industry, and the energy industry in general, has undergone some dramatic upheavals; the collapse of Enron, blackouts in California, increasing natural gas prices, the development and implementation of regional transmission organizations and a generally slow economy. As a result 13 of the 26 merchant plant projects that the IURC received petitions for were either dismissed or, following the approval of the petition, cancelled.

Three projects that were approved by the IURC have yet to be completed. The orders approving these projects specify construction start and completion deadlines that could eventually cause the IURC to revoke the certificates of necessity and convenience for those projects.

Table 2: Pending Merchant Plant Projects

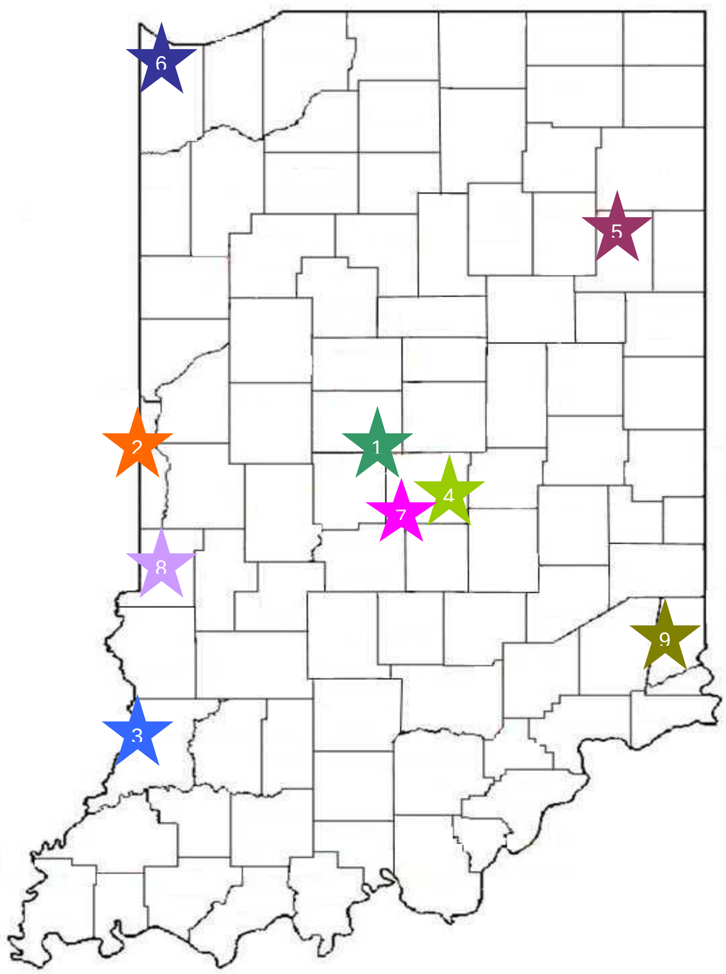
Project Name	Proposed Capacity	Location	Cause Number
Duke Energy Knox	640 MW	Knox Co.	41803
Hammond Energy	540 MW	Lake Co.	41900
Acadia Bay	630 MW	St. Joseph Co.	41966

Ultimately, 10 merchant plant projects were constructed and became operational. Over the past few years, several of these completed projects have been purchased (in full or in part) by Indiana load serving utilities.

Currently, there are two pending Causes before the IURC that are directly related to merchant plant facilities. Cause No. 42469 addresses the potential purchase of the Wheatland Generating Facility, star 3 on the following map, by PSI Energy. PSI Energy, the Office of Utility Consumer Counselor and IURC Testimonial Staff have entered into a settlement agreement regarding this purchase. An order Approving PSI's purchase of the Wheatland facility was issued on August 3, 2005.

Cause No. 42824 is a joint petition from Northern Indiana Public Service Co., EnergyUSA-TPC Corp and Whiting Clean Energy, Inc. for the approval of the purchase of capacity from Whiting by NIPSCO through a purchase power agreement with EnergyUSA. As affiliates of NiSource, the petitioners require IURC approval before the purchase power transaction can begin. The petitioners have asked for an interim order to allow the immediate purchase of power by NIPSCO from Whiting while the long-term implications of the purchase power transaction are being reviewed. An interim order was issued on July 1, 2005. In its order the Commission gave NIPSCO the authority to purchase power, on an interim basis, from Whiting Clean Energy through Whiting's cost based, FERC approved tariff. Full hearings in this cause are scheduled for later this fall.

Merchant Plant Operating in Indiana



1 IPL Georgetown Station (80 MW) Output from the plant is consumed by IPL customers. The facility began operation in May 2000. (Cause No. 41337)

2 Duke Vermillion (640 MW) The facility's eight turbines were operational in June 2000 (Cause No. 41388). March 17, 2004, the IURC approved the purchase of a 25% share of the Duke Vermillion facility by Wabash Valley Power Association (Cause No. 42495).

3 Wheatland Generating Facility (500 MW) Allegheny purchased this facility from Enron in late 2000. The facility's four turbines were operational in June 2000. (Cause No. 41411) Ownership of the Wheatland facility was transferred to PSI Energy as approved in the order in Cause No. 42469 issued August 3, 2005.

4 DTE Georgetown Station (240 MW) This plant is located on land owned by IPL. Two turbines were operational in June 2000 (Cause No. 41566). Indiana Municipal Power Agency petitioned the IURC for approval to purchase two of the three 80 MW combustion turbine units at the DTE plant in Cause No. 42455.

5 DPL Generating Station (200 MW) This plant currently has four turbines, which became operational in June 2001. (Cause No. 41685)

6 Whiting Clean Energy (525 MW) This facility began operation in April 2002 and supplies steam to the adjacent Whiting Refinery. (Cause No. 41530)

7 IPL's Harding Street Station (151 MW) This facility began operation on May 31, 2002 and is connected to the IPL system. (Cause No. 42033)

8 Sugar Creek (300 MW) Phase 1 of this facility became operational in August 2002 and is interconnected to both the Cinergy and AEP transmission systems. (Cause Nos. 41753 & 42015).

9 PSEG Lawrenceburg (1150 MW) This facility became operational in the Summer 2003 and is interconnected to AEP. (Cause No. 41757).

III. INDIANA'S ELECTRIC INDUSTRY – STATISTICS

This section is a review of the energy sales, revenue, average price and market share for Indiana's electric utilities.

Investor-Owned Utilities

There are five investor-owned utilities operating in Indiana. These utilities are the most significant in terms of generation and in number of customers served. The five investor-owned utilities that operate within the state are:

Indianapolis Power & Light, a wholly-owned subsidiary of AES Corporation;

Indiana Michigan Power, wholly owned by American Electric Power;

Northern Indiana Public Service Company, a NiSource company;

PSI Energy, a wholly-owned subsidiary of Cinergy Corporation; and,

Southern Indiana Gas & Electric Company, a subsidiary of Vectren Energy Delivery of Indiana.

Municipal Utilities

There are 72 municipally owned electric utilities in Indiana. As of June 2005, twenty-one remain under IURC jurisdiction for rate regulation. Currently 40 municipals in the state are members of the Indiana Municipal Power Agency. IMPA was created by a group of municipalities in 1980 to jointly finance and operate generation and transmission facilities and purchase power. IMPA meets its members' needs through a combination of owned generating facilities, member-dedicated generation, and purchased power.

Cooperatives

There are forty-one electric distribution co-ops operating in Indiana. As of June 2005, four co-ops remain under Commission jurisdiction for rate regulation. Most of the distribution co-ops are members of either Hoosier Energy or Wabash Valley Power Association. These two organizations are generating and transmission cooperatives formed to supply power to distribution co-ops. Hoosier Energy and WVPA serve as coordinators of bulk power supplies and transmission services for their members.

Sales, Revenues and Market Share for Electric Utilities (2004)

MWH

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	23,566,119	17,715,885	38,903,955	2,504,733	82,690,692
Rural Electric Membership Corporations	1,069,466	1,002,182	NA	5,122	2,076,770
Municipal Utilities	1,362,905	3,311,783	NA	73,439	4,748,127
Totals	**25,998,490**	**22,029,850**	**38,903,955**	**2,583,294**	**89,515,589**

REVENUE (000s)

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	$ 1,691,006	$ 1,132,724	$ 1,666,412	$ 73,672	$ 4,563,814
Rural Electric Membership Corporations	$ 79,612	$ 48,746	NA	$ 1,249	$ 129,607
Municipal Utilities	$ 94,048	$ 181,973	NA	$ 8,729	$ 284,750
Totals	**$ 1,864,666**	**$ 1,363,443**	**$ 1,666,412**	**$ 83,650**	**$ 4,978,171**

RETAIL MARKET SHARE BY MWH

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	90.64%	80.42%	100.00%	96.96%	92.38%
Rural Electric Membership Corporations	4.11%	4.55%	0.00%	0.20%	2.32%
Municipal Utilities	5.24%	15.03%	0.00%	2.84%	5.30%

RETAIL MARKET SHARE BY REVENUES

	Residential	Commercial	Industrial	Other	Totals
Investor Owned Utilities	90.69%	83.08%	100.00%	88.07%	91.68%
Rural Electric Membership Corporations	4.27%	3.58%	0.00%	1.49%	2.60%
Municipal Utilities	5.04%	13.35%	0.00%	10.44%	5.72%

Please note that REMCs and municipal utilities do not present separate commercial and industrial information in the annual reports they submit to the Commission therefore the summarized commercial and industrial data is shown under the “Commercial” heading on the tables.

Individual IOU Sales, Revenues and Market Share (2004)

MWH

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	5,524,079	4,893,770	8,109,399	84,412	18,611,660
Indianapolis Power & Light Company	4,984,432	2,027,816	7,489,292	88,858	14,590,398
Northern Indiana Public Service Company	3,104,271	3,635,045	9,309,406	142,622	16,191,344
PSI Energy, Inc.	8,451,630	5,657,740	11,452,324	2,175,361	27,737,055
Southern Indiana Gas & Electric Company	1,501,707	1,501,514	2,543,534	13,480	5,560,235
Totals	23,566,119	17,715,885	38,903,955	2,504,733	82,690,692

REVENUE (000s)

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	$ 367,015	$ 288,046	$ 342,622	$ 6,483	$ 1,004,166
Indianapolis Power & Light Company	$ 314,018	$ 137,820	$ 354,325	$ 11,118	$ 817,281
Northern Indiana Public Service Company	$ 295,122	$ 294,134	$ 414,106	$ 14,617	$ 1,017,979
PSI Energy, Inc.	$ 592,650	$ 317,835	$ 443,984	$ 39,323	$ 1,393,792
Southern Indiana Gas & Electric Company	$ 122,201	$ 94,889	$ 111,375	$ 2,131	$ 330,596
Totals	$ 1,691,006	$ 1,132,724	$ 1,666,412	$ 73,672	$ 4,563,814

AVERAGE RATE PER KWH

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	$ 0.07	$ 0.06	$ 0.04	$ 0.08	$ 0.05
Indianapolis Power & Light Company	$ 0.06	$ 0.07	$ 0.05	$ 0.13	$ 0.06
Northern Indiana Public Service Company	$ 0.10	$ 0.08	$ 0.04	$ 0.10	$ 0.06
PSI Energy, Inc.	$ 0.07	$ 0.06	$ 0.04	$ 0.02	$ 0.05
Southern Indiana Gas & Electric Company	$ 0.08	$ 0.06	$ 0.04	$ 0.16	$ 0.06

RETAIL MARKET SHARE

Utility	Residential	Commercial	Industrial	Other	Totals
Indiana Michigan Power Company	36.55%	28.69%	34.12%	0.65%	100%
Indianapolis Power & Light Company	38.42%	16.86%	43.35%	1.36%	100%
Northern Indiana Public Service Company	28.99%	28.89%	40.68%	1.44%	100%
PSI Energy, Inc.	42.52%	22.80%	31.85%	2.82%	100%
Southern Indiana Gas & Electric Company	36.96%	28.70%	33.69%	0.64%	100%

Regulated REMC Sales, Revenues and Market Share (2004)

MWH

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	322,537	200,296	3,111	525,944
Jackson County R.E.M.C.	377,963	74,476	74	452,513
Marshall County R.E.M.C.	68,893	16,303	918	86,114
Northeastern R.E.M.C.	300,073	711,107	1,019	1,012,199
Totals	1,069,466	1,002,182	5,122	2,076,770

REVENUE (000s)

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	$ 22,219	$ 10,056	$ 833	$ 33,108
Jackson County R.E.M.C.	$ 26,549	$ 4,552	$ 608	$ 31,709
Marshall County R.E.M.C.	$ 7,034	$ 1,457	$ 163	$ 8,654
Northeastern R.E.M.C.	$ 23,810	$ 32,681	$ 242	$ 56,733
Totals	$ 79,612	$ 48,746	$ 1,846	$ 130,204

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial & Industrial	Other	Totals
Harrison County R.E.M.C.	$ 0.07	$ 0.05	$ 0.27	$ 0.06
Jackson County R.E.M.C.	$ 0.07	$ 0.06	$ 0.15	$ 0.07
Marshall County R.E.M.C.	$ 0.10	$ 0.09	$ 0.18	$ 0.10
Northeastern R.E.M.C.	$ 0.08	$ 0.05	$ 0.24	$ 0.06

RETAIL MARKET SHARE

Utility	Residential	Commercial & Industrial	Other
Harrison County R.E.M.C.	67.11%	30.37%	2.52%
Jackson County R.E.M.C.	85.33%	14.63%	0.04%
Marshall County R.E.M.C.	81.28%	16.84%	1.88%
Northeastern R.E.M.C.	41.97%	57.60%	0.43%

Regulated Municipal Sales, Revenues and Market Share (2004)

MWH

Utility	Residential	Commercial	Other	Totals
Anderson Municipal Light & Power	320,018	384,533	4,877	709,428
Auburn Municipal Electric	59,963	471,236	NA	531,199
Bargersville Municipal Light & Power	30,434	16,254	1,851	48,539
Columbia City Municipal Electric	35,355	64,683	3,010	103,048
Crawfordsville Municipal Electric Light & Power	78,480	331,918	2,974	413,372
Edinburgh Municipal Electric	22,604	71,595	NA	94,199
Frankfort City Light & Power	NA	NA	NA	NA
Kingsford Heights Municipal Electric	5,316	NA	NA	5,316
Knightstown Municipal Electric	13,114	10,049	NA	23,163
Lawrenceburg Municipal Electric	27,601	116,878	1,446	145,925
Lebanon Municipal Electric	66,225	137,840	3,135	207,200
Logansport Municipal Electric	100,174	279,903	2,797	382,874
Mishawaka Municipal Electric	177,433	383,392	27,505	588,330
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	92,560	143,153	4,313	240,026
Richmond Municipal Power & Light	197,660	745,407	11,220	954,287
South Whitley Municipal Electric	18,825	NA	NA	18,825
Straughn Municipal Electric	1,525	NA	NA	1,525
Tipton Municipal Electric	38,421	73,877	1,026	113,324
Troy Municipal Electric	9,542	NA	NA	9,542
Washington City Municipal Light & Power	67,655	81,065	9,285	158,005
Totals	1,362,905	3,311,783	73,439	4,748,127

Note: "NA", or Not Available, because the utility did not file this information with the Commission in their annual report filing.

AVERAGE REVENUE PER KWH

Utility	Residential	Commercial	Other	Totals
Anderson Municipal Light & Power	$ 0.07	$ 0.06	$ 0.25	$ 0.06
Auburn Municipal Electric	$ 0.04	$ 0.04	NA	$ 0.04
Bargersville Municipal Light & Power	$ 0.07	$ 0.07	$ 0.12	$ 0.07
Columbia City Municipal Electric	$ 0.07	$ 0.06	$ 0.12	$ 0.06
Crawfordsville Municipal Electric Light & Power	$ 0.07	$ 0.05	$ 0.08	$ 0.05
Edinburgh Municipal Electric	$ 0.06	$ 0.05	NA	$ 0.06
Frankfort City Light & Power	NA	NA	NA	NA
Kingsford Heights Municipal Electric	$ 0.05	NA	NA	$ 0.09
Knightstown Municipal Electric	$ 0.06	$ 0.06	NA	$ 0.06
Lawrenceburg Municipal Electric	$ 0.06	$ 0.05	$ 0.21	$ 0.05
Lebanon Municipal Electric	$ 0.06	$ 0.05	$ 0.11	$ 0.06
Logansport Municipal Electric	$ 0.06	$ 0.05	$ 0.11	$ 0.06
Mishawaka Municipal Electric	$ 0.08	$ 0.06	$ 0.09	$ 0.07
Paoli Municipal Electric	NA	NA	NA	NA
Peru Municipal Electric Light & Power	$ 0.06	$ 0.05	$ 0.09	$ 0.06
Richmond Municipal Power & Light	$ 0.06	$ 0.05	$ 0.09	$ 0.05
South Whitley Municipal Electric	$ 0.03	NA	NA	$ 0.06
Straughn Municipal Electric	$ 0.05	NA	NA	$ 0.06
Tipton Municipal Electric	$ 0.06	$ 0.06	$ 0.10	$ 0.06
Troy Municipal Electric	$ 0.03	NA	NA	$ 0.07
Washington City Municipal Light & Power	$ 0.06	$ 0.05	$ 0.07	$ 0.06

Note: “NA”, or Not Available, because the utility did not file this information with the Commission in their annual report filing.

RETAIL MARKET SHARE

Utility	Residential	Commercial	Other
Anderson Municipal Light & Power	48.33%	49.01%	2.66%
Auburn Municipal Electric	11.38%	87.41%	1.21%
Bargersville Municipal Light & Power	60.85%	32.58%	6.57%
Columbia City Municipal Electric	35.27%	59.10%	5.63%
Crawfordsville Municipal Electric Light & Power	24.50%	74.39%	1.11%
Edinburgh Municipal Electric	25.30%	73.25%	1.45%
Frankfort City Light & Power	27.33%	69.52%	3.14%
Kingsford Heights Municipal Electric	58.91%	26.11%	14.98%
Knightstown Municipal Electric	53.63%	41.90%	4.47%
Lawrenceburg Municipal Electric	20.23%	75.78%	3.99%
Lebanon Municipal Electric	35.10%	61.81%	3.09%
Logansport Municipal Electric	30.64%	67.86%	1.50%
Mishawaka Municipal Electric	38.21%	55.33%	6.46%
Paoli Municipal Electric	NA	NA	NA
Peru Municipal Electric Light & Power	42.40%	54.90%	2.71%
Richmond Municipal Power & Light	25.38%	72.67%	1.95%
South Whitley Municipal Electric	45.74%	45.12%	9.13%
Straughn Municipal Electric	82.65%	5.10%	12.24%
Tipton Municipal Electric	35.55%	62.92%	1.53%
Troy Municipal Electric	37.37%	59.82%	2.81%
Washington City Municipal Light & Power	46.71%	46.37%	6.93%

Generation Capacity by Utility (MW)

Utility	Summer
Indiana Michigan Power Company	5,044
Indianapolis Power & Light Company	3,290
Northern Indiana Public Service Company	2,890
PSI Energy, Inc.	7,070
Southern Indiana Gas & Electric Company	1,351
Hoosier Energy	1,018
Wabash Valley Power Association	310
Indiana Municipal Power Agency	601

Note: The main sources for these values are the responses to the 2004 IURC Annual Summer Capacity Surveys

Average Revenue per kWh by State (Ranked in Descending Order by Residential Rate)

STATE	2002 Residential	2002 Average	2003 Residential	2003 Average	2004 Residential	2004 Average
Hawaii	15.63	13.39	16.35	14.25	17.10	14.94
New York	13.58	11.29	12.89	10.46	13.78	11.29
Vermont	12.78	10.87	12.36	10.94	12.67	11.02
Maine	11.98	11.36	12.89	9.78	12.59	10.48
New Hampshire	11.77	10.49	11.65	10.55	12.10	11.13
Rhode Island	10.21	9.19	10.50	9.36	12.09	10.95
California	12.90	12.50	12.24	11.22	11.98	11.01
Alaska	12.05	10.46	11.47	14.77	11.83	10.61
Connecticut	10.96	9.73	10.53	9.49	11.76	10.55
Massachusetts	10.97	10.19	10.61	9.44	11.47	10.35
New Jersey	10.38	9.31	9.75	8.77	10.68	9.50
Nevada	9.43	8.42	9.49	8.24	9.08	7.83
Pennsylvania	9.71	8.01	8.95	7.84	9.02	7.88
Florida	8.16	7.31	8.11	7.40	8.76	8.03
Texas	8.05	6.62	7.83	6.83	8.66	7.18
Wisconsin	8.18	6.28	8.10	6.34	8.64	6.64
New Mexico	8.50	6.73	8.36	6.84	8.36	6.94
Michigan	8.28	6.92	8.31	6.86	8.31	6.91
Iowa	8.35	6.01	7.73	5.79	8.14	6.00
North Carolina	8.19	6.74	7.84	6.66	8.06	6.88
Colorado	7.37	6.00	7.58	6.34	8.00	6.73
Delaware	8.70	7.05	7.72	6.51	7.86	6.65
Illinois	8.39	6.97	7.50	6.87	7.86	6.54
Ohio	8.29	6.66	7.44	6.42	7.83	6.61
South Carolina	7.72	5.83	7.48	5.95	7.52	5.97
Arizona	8.27	7.21	7.36	6.58	7.46	6.88
Louisiana	7.10	5.99	6.75	5.96	7.45	6.71
Virginia	7.79	6.23	7.14	6.12	7.43	6.29
Minnesota	7.49	5.84	7.17	5.64	7.40	5.88
Georgia	7.63	6.24	7.18	6.17	7.37	6.30
District of Columbia	7.82	7.37	7.48	6.57	7.35	6.42
Mississippi	7.28	6.24	6.94	6.28	7.33	6.43
Montana	7.23	5.75	7.07	6.02	7.28	5.87
Alabama	7.12	5.71	6.80	5.74	7.15	5.89
Kansas	7.67	6.31	7.16	6.14	7.15	5.98
Oregon	7.12	6.32	6.96	6.34	7.11	6.29
Maryland	7.71	6.21	6.70	5.55	7.09	6.34
South Dakota	7.40	6.26	6.96	6.15	6.94	6.25
Indiana	**6.91**	**5.34**	**6.49**	**5.30**	**6.76**	**5.35**

STATE	**2002**	**2002**	**2003**	**2003**	**2004**	**2004**
	Residential	**Average**	**Residential**	**Average**	**Residential**	**Average**
Tennessee	6.41	5.72	6.29	5.78	6.76	6.12
Oklahoma	6.73	5.59	6.37	5.65	6.72	5.69
Arkansas	7.25	5.61	6.64	5.42	6.70	5.27
Utah	6.79	5.39	6.56	5.09	6.62	5.25
Wyoming	6.97	4.68	6.59	4.66	6.53	4.78
Washington	6.29	5.80	6.15	5.83	6.40	5.81
Missouri	7.06	6.09	6.01	5.29	6.27	5.43
West Virginia	6.23	5.11	6.01	5.11	6.02	5.15
North Dakota	6.39	5.45	5.85	5.24	5.95	5.36
Nebraska	6.73	5.55	5.83	5.09	5.91	5.18
Idaho	6.59	5.58	6.62	5.87	5.74	4.93
Kentucky	5.65	4.26	5.41	4.22	5.67	4.34
U.S. Average	**8.46**	**7.21**	**7.99**	**7.02**	**8.38**	**7.22**

Source: Energy Information Administration: "Electric Monthly Power” June 2005 (Table 5.6 B).

IV. GLOSSARY

Affiliate: A company, partnership or other entity with a corporate structure that includes a utility engaging in or arranging for an unregulated retail sale of gas or electric energy or related services.

Capacity: The size of a plant (not its output). Electric utilities measure size in kilowatts or megawatts and gas utilities measure size in cubic feet of delivery capability.

Cooperative: A business entity similar to a corporation, except that ownership is vested in members rather than stockholders and benefits are in the form of products or services rather than profits.

Distribution: The component of a gas or electric system that delivers gas or electricity from the transmission component of the system to the end-user. Usually the energy has been altered from a high pressure or voltage level at the transmission level to a level that is usable by the consumer. Distribution is also used to describe the facilities used in this process.

Generation: The process of producing electricity. Also refers to the assets used to produce electricity for transmission and distribution.

Grandfathered Agreements (GFAs): Transmission service agreements currently in force in the MISO region that were entered into prior to September 16, 1998

Holding Company: A corporate structure where one company holds the stock (ownership) of one or more other companies but does not directly engage in the operation of any of its business.

Independent System Operator (ISO): An independent organization or institution that controls the transmission system in a particular region. The ISO would have no corporate relationship with the transmission-owning utilities, and therefore would be able to assure fair and comparable access to the transmission system for all users.

Kilowatt (kW): A basic unit of measurement; 1kW = 1,000 watts.

Kilowatt-Hour (kWh): One kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

Megawatt (MW): One thousand kilowatts or one million watts.

Megawatt-Hour (MWh): One megawatt of power supplied to or taken from an electric circuit steadily for one hour.

Midwest Market Initiative (MMI): In December 2002, the Midwest ISO announced the Midwest Market Initiative ("MMI"). The MMI refers to the preparation and implementation of the Midwest ISO wholesale energy market in the Midwest with a target launch date of December 2003. The MMI involves the formation of real time and day ahead markets for trading electricity based on hourly locational marginal pricing.

Municipal Utility: A utility that is owned and operated by a municipal government. These utilities are organized as nonprofit local government agencies and pay no taxes or dividends; they raise capital through the issuance of tax-free bonds.

Organization of Midwest ISO States ("OMS"): A group of state utility commissions in the MISO footprint that initiated the formation of the country's first so-called regional state committee. The OMS will act as an adviser on some MISO functions and attempt to plan transmission investments on a regional, rather than state-specific basis.

Reactive Power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).

Reliability: A term used in both the electric and gas industry to describe the utility's ability to provide uninterrupted service of gas or electricity. Reliability of service can be compromised at any level of service: generation or production, transmission or distribution.

Service Territory: Under the current regulatory environment, an electric utility is granted a franchise to provide energy to a specified geographical territory, designated as a service territory.

State Estimator: a sophisticated mathematical "what if" simulator that allows operators and engineers to evaluate the health of the power system every few minutes by simulating the grid's response to hypothetical equipment failures.

Transmission: The process of transferring energy (either gas or electricity) from the production or generation source to the point of distribution. Also refers to the facilities used for this process.

Voltage: the rate at which energy is drawn from a source that produces a flow of electricity in a circuit; expressed in volts.

V. LIST OF ACRONYMNS

AEP	American Electric Power
APCO	Appalachian Power Company, subsidiary of AEP
BTU	British Thermal Unit
CAC	Citizens Action Coalition
CNUC	CN Utility Consulting
CSPCO	Columbus and Southern Power Company, subsidiary of AEP
CT	Combustion Turbine
EPA	Environmental Protection Agency
FAC	Fuel Adjustment Cost Charge
FERC	Federal Energy Regulatory Commission
GFAs	Grandfathered Agreements
IDEM	Indiana Department of Environmental Management
IIG	Indiana Industrial Group
I&M	Indiana Michigan Power Company, subsidiary of AEP
IMPA	Indiana Municipal Power Agency
IOU	Investor-owned Utility
IPL	Indianapolis Power and Light
ISO	Independent System Operator
ITC	Independent Transmission Company
IURC	Indiana Utility Regulatory Commission
JOA	Joint Operating Agreement
JTS	Joint Transmission System
KPCO	Kentucky Power Company, subsidiary of AEP
LMP	Locational Marginal Pricing
MMI	Midwest Market Initiative
MW	Megawatt
MWH	Megawatt Hour
MISO	Midwest Independent Transmission System Operator
NERC	North American Electric Reliability Council
NO_x	Nitrogen Oxides
NIPSCO	Northern Indiana Public Service Company
NOPR	Notice of Proposed Rulemaking
OMS	Organization of Midwest ISO States ("OMS"):
OUCC	Office of Utility Consumer Counselor
OPCO	Ohio Power Company, subsidiary of AEP
PSI	PSI Energy

PPTT	Purchased Power and Transmission Tracker
REMC	Rural Electric Membership Cooperative
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SIGECO	Southern Indiana Gas & Electric Company
SMD	Standard Market Design
SO_2	Sulfur Dioxide
WVPA	Wabash Valley Power Association